Chapter B8: Alternative Options - Electricity Market Model Analysis

INTRODUCTION

Chapter B7: Alternative Options - Costs and Economic Impacts described the total costs and economic impacts of four of the six alternative regulatory options considered by EPA. This chapter presents EPA's electricity market model analysis using ICF Consulting's Integrated Planning Model (IPM®) for two of those alternative options: (1) the waterbody/capacity-based option (Option 1), and (2) the all cooling towers option (Option 4).

CHAPTER CONTENTS

B8-1 OVERVIEW OF IPM ANALYSIS OF ALTERNATIVE OPTIONS

EPA used the IPM, an integrated energy market model, to analyze two potential effects of the alternative regulatory options: (1) potential energy effects at the national and regional levels, as required by Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use"); and (2) potential economic impacts on in-scope facilities.[1] Both alternative options analyzed using the IPM have more stringent compliance technology requirements than the proposed rule. Specifically, both options would require a subset of existing facilities to install recirculating wet cooling towers.

Table B8-1 below presents the number and capacity of facilities in each NERC region that EPA estimated would install a cooling tower under the waterbody/capacity-based option and the all cooling towers option, respectively. The table presents the percentage of total pre-run capacity in each region that was costed with a cooling tower under the two alternative options. Pre-run capacity is defined as the current operating, and planned-committed generating units, as identified by ICF. It is used for this measure, rather than the base case capacity. Since the base case results reflect a post-compliance landscape in which the effects of cooling tower installation are already modeled, the base case would no longer provide a useful measure of the magnitude of capacity effected by the alternative options. [2]

[1] *Chapter B3: Electricity Market Model Analysis* presents a detailed description of the IPM and a discussion of the methodology EPA used to estimate economic impacts using the IPM.

[2] Note that of the 539 surveyed facilities subject to the section 316(b) Phase II Rule, nine are not modeled in the IPM. Three facilities are in Hawaii, one is in Alaska. Neither state is represented in the IPM. One facility is identified as an "Unspecified Resource" and does not report on any EIA forms. Four facilities are on-site facilities that do not provide electricity to the grid. The 530 in-scope facilities modeled by the IPM were weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey and thus represent a total of 540 facilities industry-wide. The results for Phase II facilities in the remainder of this chapter, except where noted, are based on the 540 weighted facilities.

Table B8-1: Distribution of Cooling Towers in 2008 (MW; by NERC Region)[a, b]							
NERC Region	National Pre-Run Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
		# of Facilities	Pre - Run Capacity	% of Pre-Run Capacity	# of Facilities	Pre-Run Capacity	% of Pre-Run Capacity
ECAR	124,220	0	0	0.0%	77	54,200	43.6%
ERCOT	79,590	4	3,840	4.8%	35	30,650	38.5%
FRCC	53,680	7	8,970	16.7%	23	18,320	34.1%
MAAC	67,350	9	9,320	13.8%	26	19,480	28.9%
MAIN	67,520	0	0	0.0%	40	27,350	40.5%
MAPP	39,120	0	0	0.0%	39	14,790	37.8%
NPCC	81,070	18	13,530	16.7%	58	35,840	44.2%
SERC	205,310	5	7,390	3.6%	76	84,590	41.2%
SPP	51,340	0	0	0.0%	18	7,450	14.5%
WSCC	172,790	9	12,200	7.1%	24	19,470	11.3%
Total	**941,990**	**52**	**55,250**	**5.9%**	**416**	**312,140**	**33.1%**

a Capacities have been rounded to the nearest 10, and percentages have been rounded to the nearest 10th.

b The number of facilities and pre-run capacity under each option have been weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey.

Source: IPM analysis: Section 316(b) Base Case 2000, EPA Analysis 2002.

Waterbody/capacity-based option: Overall, EPA estimates that 54 facilities would install a cooling tower under this option. Two of these facilities are located in Hawaii, and are therefore not included in the IPM analysis. Table B8-1 shows that 52 facilities in six NERC regions are estimated to be required to install wet cooling towers under this option. In aggregate, these facilities account for 55,250 MW of capacity or 5.9 percent of the total pre-run capacity. Three regions (FRCC, MAAC, and NPCC) would be required to install cooling towers on more than 13 percent of total base case capacity.

All cooling towers option: Overall, EPA estimates that 426 facilities would install a cooling tower under this option. Ten of these facilities are not modeled. In total, 416 facilities across all regions are estimated to install wet cooling towers under this option, accounting for 312,140 MW of capacity or 33.1 percent of total pre-run capacity. EPA estimates that at least 10 percent of capacity in each region would install cooling towers under this option, and four of the 10 regions would install cooling towers on more than 40 percent of total base case capacity. ECAR would install cooling towers on the largest number of facilities (77), and the second largest percentage of capacity (43.6 percent).

B8-2 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of the proposed Phase II rule. Market level impacts associated with each of the alternative options are assessed using the following seven impact measures: (1) plant closures, (2) capacity changes, (3) generation changes, (4) revenue changes, (5) variable production cost changes, (6) fuel cost changes, and (7) electricity price changes.[3] These measures were developed for model run year 2013.[4] A detailed description of each of the impact measures discussed below is presented in Section B3-3.1 of *Chapter B3: Electricity Market Model Analysis*.

3 All of the information presented in section B8-2 is unweighted.

4 The IPM model simulates electricity market function for a period of 25 years. Model output is provided for five user-specified model run years. EPA selected three run years to provide output across the ten year compliance period for the rule. Analyses of regulatory options are based on output for model run years that reflect a scenario in which all facilities are operating in their post-compliance condition. Options requiring the installation of cooling towers are analyzed using output from model run year 2013.

a. Market plant closures

Table B8-2 presents total base case capacity as well as the capacity of plant closures and the percentage of total base case capacity closed under the two alternative options by NERC region.

Table B8-2: National Capacity of Closure Units by 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closure Capacity	% of Base Case	Closure Capacity	% of Base Case
ECAR	122,080	0	0.0%	110	0.1%
ERCOT	80,230	0	0.0%	460	0.6%
FRCC	52,850	0	0.0%	90	0.2%
MAAC	65,270	0	0.0%	(40)	-0.1%
MAIN	61,380	0	0.0%	0	0.0%
MAPP	36,660	0	0.0%	0	0.0%
NPCC	74,080	840	1.1%	800	1.1%
SERC	205,210	0	0.0%	(170)	-0.1%
SPP	51,380	0	0.0%	20	0.0%
WSCC	173,600	2,170	1.3%	2,370	1.4%
Total	**922,740**	**3,010**	**0.3%**	**3,640**	**0.4%**

[a] Capacities have been rounded to the nearest 10 and percent changes have been rounded to the nearest 10th.

Source: *IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.*

Waterbody/capacity-based option: In aggregate, 0.3 percent of total base case capacity closes as a result of this option. Two regions, NPCC and WSCC, experience closures of existing capacity. Of the 840 MW of capacity that closes in NPCC (1.1 percent of total base case capacity), 440 MW is oil/gas fired capacity while the remaining 400 MW is nuclear capacity. In WSCC 2,170 MW of capacity, or 1.3% of the total capacity in the region closes. The vast majority of this capacity, 99 percent (2,150 MW), represents nuclear capacity.

All cooling towers option: Overall, 0.4 percent of total base case capacity closes under this option. Six regions experience closures of existing capacity. Of the 3,640 MW of total capacity that closes under this option, 2,370 MW (65 percent) occur in WSCC. This closure represents 1.4 percent of total base case capacity in WSCC. Conversely, two regions, MAAC and SERC, experience avoided closures as a result of this option. In these regions, facilities that would have closed in the absence of section 316(b) regulation remain open under this option. This could occur as a result of increases in electricity prices, which could increase the number of plants that can profitably supply generation, or if a facility's compliance costs are low relative to other affected facilities.

b. Market capacity

❖ *Total domestic capacity*

Table B8-3 presents the total domestic capacity under the base case and the two alternative regulatory options by NERC region. The total domestic capacity shows the effects of closures, additions, repowerings, and energy penalties. The change in capacity associated with each option is expressed as a percentage of total base case capacity.

Table B8-3: National Domestic Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity	% Change	Capacity	% Change
ECAR	122,080	122,260	0.1%	121,330	-0.6%
ERCOT	80,230	80,160	-0.1%	79,820	-0.5%
FRCC	52,850	52,710	-0.3%	52,580	-0.5%
MAAC	65,270	65,170	-0.2%	65,050	-0.3%
MAIN	61,380	61,380	0.0%	61,100	-0.5%
MAPP	36,660	36,640	-0.1%	36,410	-0.7%
NPCC	74,080	73,840	-0.3%	73,650	-0.6%
SERC	205,210	204,970	-0.1%	204,820	-0.2%
SPP	51,380	51,360	0.0%	51,320	-0.1%
WSCC	173,600	173,450	-0.1%	173,280	-0.2%
Total	**922,740**	**921,940**	**-0.1%**	**919,360**	**-0.4%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Overall, there is a reduction in total available capacity of approximately 800 MW, or 0.1 percent of total base case capacity. Therefore, this option would be considered a significant energy action under Executive Order 13211, and EPA would be required to prepare a Statement of Energy Effects if the Agency proposed this regulatory option. The largest percentage decrease in capacity occurs in FRCC and NPCC with 0.3 percent of base case capacity. In all other regions, the capacity reduction is less than 0.2 percent.

All cooling towers option: In aggregate, there is a reduction in total available capacity of approximately 3,380 MW, or 0.4 percent of total base case capacity. Therefore, this option would also be considered a significant energy action, and EPA would be required to prepare a Statement of Energy Effects if the Agency proposed this regulatory option. The largest percentage decrease in capacity occurs in MAPP with 0.7 percent of base case capacity.

❖ *Capacity additions*

Table B8-4 presents the total base case capacity as well as the total cumulative capacity additions through 2013, under the base case and both alternative options by NERC region. For each of these three scenarios, total capacity additions for each region is expressed as a percentage of total base case capacity. Finally, the difference between capacity additions as a percentage of total base case capacity for the two regulatory options and base case capacity additions as a percentage of total base case capacity is calculated and presented in bold.

Table B8-4: National Domestic Capacity Additions in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Total Capacity	Base Case Capacity Additions	Additions as a % of Total Base Case Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Capacity Additions	Additions as a % of Total Base Case Capacity	Difference	Capacity Additions	Additions as a % of Total Base Case Capacity	Difference
ECAR	122,080	12,030	9.9%	12,210	10.0%	**0.1%**	14,400	11.8%	**1.9%**
ERCOT	80,230	6,990	8.7%	6,980	8.7%	**0.0%**	7,280	9.1%	**0.4%**
FRCC	52,850	13,600	25.7%	13,590	25.7%	**0.0%**	13,670	25.9%	**0.1%**
MAAC	65,270	7,290	11.2%	7,330	11.2%	**0.1%**	7,350	11.3%	**0.1%**
MAIN	61,380	10,750	17.5%	10,740	17.5%	**0.0%**	11,320	18.4%	**0.9%**
MAPP	36,660	3,980	10.9%	3,960	10.8%	**-0.1%**	3,920	10.7%	**-0.2%**
NPCC	74,080	7,030	9.5%	8,070	10.9%	**1.4%**	8,590	11.6%	**2.1%**
SERC	205,210	40,660	19.8%	40,520	19.7%	**-0.1%**	41,520	20.2%	**0.4%**
SPP	51,380	2,420	4.7%	2,410	4.7%	**0.0%**	2,520	4.9%	**0.2%**
WSCC	173,600	14,120	8.1%	15,340	8.8%	**0.7%**	15,420	8.9%	**0.7%**
Total	**922,740**	**118,870**	**12.9%**	**121,150**	**13.1%**	**0.2%**	**125,990**	**13.7%**	**0.8%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, capacity additions as a percentage of base case capacity increases by 0.2 percent under this option as compared to the base case. The two largest increases in this metric occur in NPCC and WSCC, with increases of 1.4 percent and 0.7 percent, respectively. These increases occur in part due to the closures that are experienced under this option. MAPP and SERC experience decreases in capacity additions as a percentage of base case capacity.

All cooling towers option: Overall, capacity additions as a percentage of base case capacity increase by 0.8 percent under the all cooling tower option as compared to the base case. As was the case under the waterbody/capacity-based option, the largest increase in this metric occurs in NPCC (2.1 percent). MAPP experiences a decrease in capacity additions as a percentage of base case capacity of 0.2 percent.

❖ ***Repowering capacity***

Table B8-5 presents the total base case capacity as well as total repowered capacity under the base case and both alternative options by NERC region. For each of the three scenarios total repowered capacity for each region is expressed as a percentage of total base case capacity. Finally, the difference between repowered capacity as a percentage of total base case capacity for the two regulatory options and the base case repowered capacity as a percentage of total base case capacity is calculated and presented in bold.

Table B8-5: National Repowering Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Total Capacity	Base Case Repowered Capacity	Repowering as a % of Total Base Case Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Repowered Capacity	Repowering as a % of Total Base Case Capacity	Difference	Repowered Capacity	Repowering as a % of Total Base Case Capacity	Difference
ECAR	122,080	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
ERCOT	80,230	1,390	1.7%	1,410	1.8%	**0.0%**	5,510	6.9%	**5.1%**
FRCC	52,850	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
MAAC	65,270	1,660	2.5%	1,640	2.5%	**0.0%**	1,640	2.5%	**0.0%**
MAIN	61,380	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
MAPP	36,660	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
NPCC	74,080	8,460	11.4%	7,900	10.7%	**-0.8%**	7,730	10.4%	**-1.0%**
SERC	205,210	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
SPP	51,380	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
WSCC	173,600	7,020	4.0%	8,960	5.2%	**1.1%**	7,770	4.5%	**0.4%**
Total	**922,740**	**18,530**	**2.0%**	**19,910**	**2.2%**	**0.2%**	**22,650**	**2.5%**	**0.4%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, this option results in a 0.2 percent increase(450 MW) in repowered capacity as a percentage of total base case capacity relative to the base case. Existing facilities in four NERC regions experience repowering: WSCC, NPCC, MAAC and ERCOT. Of the 19,910 MW of repowered capacity, 8,960 MW, or 45 percent, is located in WSCC. This region also experiences the largest change in repowered capacity as a percentage of total base case capacity, increasing by 1.1 percent. NPCC experiences the second largest absolute amount of repowered capacity with 7,900 MW. However, this represents a 0.8 percent decrease compared to the base case.

All cooling towers option: Overall, repowered capacity as a percentage of total base case capacity increases by 0.4 percent under this option as compared to the base case. ERCOT experiences the largest change in this metric, increasing 5.1 percent. As was the case under the waterbody/capacity-based option, WSCC and NPCC are responsible for the majority (68 percent) of the repowered capacity under this option.

c. Market generation

Table B8-6 presents total generation under the base case and the two alternative regulatory options by NERC region. Total generation associated with each option is expressed as a percentage of total base case generation. The IPM model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with each of the regulatory options.[5]

Table B8-6: National Generation in 2013 (million MWh; by NERC Region)[a]

NERC Region	Base Case Generation	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Generation	% Change	Generation	% Change
ECAR	661	661	0.0%	660	-0.2%
ERCOT	360	360	0.0%	360	0.0%
FRCC	199	199	0.0%	199	0.0%
MAAC	284	284	-0.2%	288	1.1%
MAIN	286	286	0.3%	285	-0.3%
MAPP	187	187	0.0%	186	-0.3%
NPCC	285	285	-0.1%	284	-0.7%
SERC	987	987	0.0%	988	0.0%
SPP	228	228	0.0%	229	0.4%
WSCC	784	784	0.0%	784	0.0%
Total	**4,261**	**4,261**	**0.0%**	**4,261**	**0.0%**

a Percent changes have been rounded to the nearest 10^{th}.

Source: *IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.*

Waterbody/capacity-based option: While there is no change in total generation under this option, there is a minor redistribution of generation among regions. The largest increase in generation occurs in MAIN, at 0.3 percent while MAAC experiences a decrease of 0.2 percent.

All cooling towers option: While there is no change in total generation under this option, there is a redistribution of generation among regions. MAAC experiences a 1.1 percent increase in total generation while NPCC experiences a decrease of 0.7 percent.

5 Section B3-6 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of this assumption.

d. Market revenues

Table B8-7 presents the base case revenues, as well as total revenues under the each of the alternative options and the percent change in revenues between the base case and the two alternative options by NERC region.

Table B8-7: National Revenues in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Revenues	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Revenues	% Change	Revenues	% Change
ECAR	22,180	22,190	0.0%	22,440	1.2%
ERCOT	12,060	12,060	0.0%	12,090	0.2%
FRCC	7,840	7,820	-0.3%	7,810	-0.4%
MAAC	10,960	10,940	-0.2%	11,070	1.0%
MAIN	9,960	9,980	0.2%	10,000	0.4%
MAPP	5,960	5,960	0.0%	5,990	0.5%
NPCC	11,020	11,280	2.4%	11,330	2.8%
SERC	34,360	34,360	0.0%	34,450	0.3%
SPP	7,750	7,750	0.0%	7,770	0.3%
WSCC	24,840	24,890	0.2%	24,880	0.2%
Total	**146,930**	**147,230**	**0.2%**	**147,830**	**0.6%**

[a] Revenues have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, total revenues increase by 0.2 percent under this option. Since generation is fixed, the overall increase in revenues is due price increases (Tables B8-10 and B8-11). Five of the ten regions experience a change in this metric. The largest change in revenues occurs in NPCC, which experiences an increase of 2.4 percent. As generation would remain virtually unchanged in this region, the increase in capacity prices presented in Table B8-11 is the most likely explanation for this increase in revenues. The largest decrease in revenues, 0.3 percent, occurs in FRCC. With stable generation and an increase in energy price in this region, this reduction is caused by the decrease in capacity prices (see Table B8-11).

All cooling towers option: Overall, this option results in a 0.6 percent increase in total revenues. As is the case under the waterbody/capacity-based option, the largest increase (2.8 percent) occurs in NPCC, while the only decrease (0.4 percent) occurs in FRCC. The results presented in Table B8-11 suggest that changes in capacity prices are likely be responsible for these changes in revenues.

e. Market variable production costs

Table B8-8 presents the variable production costs for the base case as well as production costs and percentage change in base case production costs under each of the two alternative regulatory options by NERC region. Variable production costs include fuel and other variable O&M costs and are the primary determinant of when and how often a plant's generation units are dispatched.

Table B8-8: National Variable Production Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Production Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Production Costs	% Change	Production Costs	% Change
ECAR	11.90	11.90	0.0%	12.19	2.4%
ERCOT	17.27	17.27	0.0%	17.33	0.3%
FRCC	18.17	18.25	0.4%	18.31	0.7%
MAAC	13.06	13.15	0.7%	13.29	1.8%
MAIN	12.22	12.25	0.2%	12.50	2.3%
MAPP	11.20	11.20	0.0%	11.32	1.0%
NPCC	17.88	17.98	0.5%	18.07	1.0%
SERC	12.73	12.74	0.1%	12.89	1.2%
SPP	13.63	13.63	0.0%	13.70	0.5%
WSCC	11.66	11.89	1.9%	11.89	1.9%

a Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: This option increases variable production costs in six of the ten NERC regions under this option while remaining unchanged in the other four. The largest increase in variable production costs occurs in WSCC, which experiences a 1.9 percent increase. The most likely cause for this increase is the economic closure of 2,170 MW of existing capacity that occurs in this region (see Table B8-2). Of the total closures in this region, 2,150 MW comes from nuclear capacity, a low-cost source of generation. Although new capacity comes online in the form of capacity additions and repowerings (see Tables B8-4 and B8-5), the new capacity is in the form of combined-cycle and combustion turbine capacity, prime movers that have higher average variable production costs than the existing nuclear capacity being replaced. As a result, the average production cost per MWh of generation for the region increases.

Only two other NERC regions experience an increase in production costs of 0.5 percent or more, MAAC and NPCC, with increases of 0.7 percent and 0.5 percent respectively. These increases could be associated with an increase in variable O&M costs at facilities that are estimated to install recirculating wet cooling towers under this option. As shown in Table B8-1, a relatively high percentage of base case capacity in these regions are required to install recirculating wet cooling towers under this option.

All cooling towers option: This option increases variable production costs per MWh of generation in each of the ten NERC regions with seven regions experiencing increases of 1 percent or more. The two largest impacts in this measure occur in ECAR and MAIN, where the production costs increase by 2.4 percent and 2.3 percent, respectively. This result is not surprising given that approximately 40 to 45 percent of base case capacity in each of these regions is estimated to install recirculating wet cooling towers under this option (see Table B8-1).

f. Market fuel costs

Table B8-9 presents the base case fuel costs, as well as fuel costs under the two alternative options, and the percent change in fuel costs between the base case and the options by NERC region.

Table B8-9: National Fuel Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Fuel Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Fuel Costs	% Change	Fuel Costs	% Change
ECAR	9.46	9.45	-0.1%	9.76	3.2%
ERCOT	15.24	15.24	0.0%	15.33	0.6%
FRCC	16.26	16.35	0.6%	16.42	1.0%
MAAC	11.01	11.11	0.8%	11.26	2.2%
MAIN	10.17	10.20	0.3%	10.47	2.9%
MAPP	9.15	9.14	0.0%	9.26	1.2%
NPCC	16.56	16.67	0.6%	16.76	1.2%
SERC	10.87	10.88	0.1%	11.03	1.5%
SPP	11.77	11.77	0.0%	11.85	0.7%
WSCC	10.14	10.39	2.5%	10.40	2.6%

[a] Percent changes have been rounded to the nearest 10^{th}.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Seven of the ten NERC regions experience a change in fuel cost as a result of this option. The largest increase in fuel costs per MWh of generation occurs in WSCC at 2.5 percent. This increase occurs in part due to the nuclear facility closure. Since regional demand for generation does not change, new and repowered combined cycle and combustion turbine capacity comes on-line. This capacity, and its subsequent generation, increases the demand on the fuel supply, increasing the cost of fuel in the region. No other region experiences an increase in fuel costs of more than 0.8 percent. One region, ECAR, experiences a decrease of 0.1 percent.

All cooling towers option: The cost of fuel increases in each of the ten NERC regions under this option. These increases exceed 1.0 percent in all but two regions, ERCOT and SPP. ECAR and MAIN experience the greatest impact in this measure as fuel costs per MWh of generation increase by 3.2 percent and 2.9 percent, respectively.

g. Market electricity prices

Table B8-10 presents base case energy prices as well as energy prices and the percent change under each of the two alternative options, by NERC region. Table B8-11 presents the same information for capacity prices in each region.

Table B8-10: Energy Prices in 2013 ($2001 per KWh; by NERC Region)[a]

NERC Region	Base Case Energy Prices	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Energy Prices	% Change	Energy Prices	% Change
ECAR	23.12	23.13	0.0%	23.54	1.8%
ERCOT	26.88	26.89	0.0%	27.00	0.4%
FRCC	29.21	29.36	0.5%	29.52	1.1%
MAAC	26.98	27.15	0.6%	27.14	0.6%
MAIN	22.95	22.97	0.1%	23.16	0.9%
MAPP	21.68	21.69	0.0%	21.70	0.1%
NPCC	30.84	30.76	-0.3%	30.87	0.1%
SERC	24.64	24.65	0.0%	24.74	0.4%
SPP	23.95	23.95	0.0%	24.02	0.3%
WSCC	26.25	26.21	-0.1%	26.27	0.1%

[a] Percent changes have been rounded to the nearest 10^{th}.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: The average annual price received for the sale of electricity remains unchanged in five NERC regions under this option. In three regions (FRCC, MAAC, and MAIN), it increases, and in two regions (NPCC and WSCC), it decreases. The two largest increases in energy prices occur in MAAC (0.6 percent) and FRCC (0.5 percent). All other things being equal, energy prices increase with an increase in the variable production costs of the last unit to be dispatched. Table B8-8 showed that MAAC and FRCC both experience an increase in variable production costs associated with a relatively high percentage of base case capacity that is estimated to install recirculating wet cooling towers under this option (see Table B8-1). Energy prices decrease in NPCC and WSCC despite increases in both production and fuel costs. This result is counter-intuitive but is due to the fact that each NERC region in the IPM consists of several subregions. For example, NPCC consists of five sub-regions. Energy prices increase in four of the five sub-regions but decrease in the largest sub-region. This decrease outweighs the increases in the other sub-regions while the other four sub-regions are dominant in determining the average fuel and production costs in NPCC.

All cooling towers option: Energy prices increase in each of the ten NERC regions under this option, with the largest increases of 1.8 percent and 1.1 percent occurring in ECAR and FRCC, respectively. As indicated above, an increase in energy prices results from an increase in variable production costs. Table B8-8 showed that variable production costs increase for all 10 NERC regions under this option.

Table B8-11: Capacity Prices in 2013 ($2001 per KW per year; by NERC Region)[a]

NERC Region	Base Case Capacity Prices	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity Prices	% Change	Capacity Prices	% Change
ECAR	56.62	56.53	-0.2%	57.02	0.7%
ERCOT	29.93	29.86	-0.2%	29.91	-0.1%
FRCC	38.52	37.77	-2.0%	37.06	-3.8%
MAAC	50.40	49.63	-1.5%	50.28	-0.2%
MAIN	55.63	55.57	-0.1%	55.80	0.3%
MAPP	52.64	52.59	-0.1%	54.19	3.0%
NPCC	32.57	36.86	13.2%	37.98	16.6%
SERC	48.98	48.96	0.0%	48.96	0.0%
SPP	44.83	44.81	0.0%	44.52	-0.7%
WSCC	26.81	27.34	2.0%	27.08	1.0%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: The majority of NERC regions experience a reduction in capacity prices. Only two regions, NPCC and WSCC, experience an increase. The largest increase in capacity price occurs in NPCC (13.2 percent). This increase is likely the result of the decrease in total available capacity in this region, in part due to the closure of existing capacity (see Table B8-2) while generation, or demand for electricity, remains stable. This combination of factors suggests that a higher percentage of existing capacity is required to meet demand in this region. As such, facilities that are not dispatched under the base case, and thus are available for reserves, are dispatched under this option. As a result, less capacity would be available for reserves and capacity price increases.

All cooling towers option: All but one NERC region experiences a change in capacity prices under this option. As was the case under the waterbody/capacity-based option, the largest increase in capacity prices occurs in NPCC (16.6 percent), and the largest decrease in capacity prices occurs in FRCC (3.8 percent). No other region experiences increases or decreases of this magnitude in capacity prices under this option.

B8-3 Analysis of Phase II Facilities

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Fifteen of the 540 Phase II facilities are identified as baseline closures, and are therefore not represented in these results. (In some cases, a facility that is a closure in the base case is operational in the post-compliance run. Such facilities are not represented in the base case but would be represented in the post-compliance scenario.) Except where noted, the results in this section therefore reflect the 525 weighted, non-closure, Phase II facilities modeled by the IPM.

EPA used the IPM results to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which is not subject to this rule.

B8-3.1 Group of Phase II Facilities

This section presents the analysis of the potential impacts of each of the two alternative options on the group of Phase II facilities. Section B3-3.2 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of the seven impact measures developed using IPM output from model run year 2013 and used to assess potential changes in the economic and operational characteristics of this group of facilities.

a. Phase II plant closures

Table B8-12 presents the number of operational Phase II facilities under the base case and, for the two alternative options, the number and percent of total Phase II facilities that would close by NERC region. Table B8-13 presents the base case capacity of Phase II facilities and the capacity of closures under each option by NERC region. The table also presents capacity of closures expressed as a percentage of total base case Phase II capacity.

Table B8-12: Number of Facilities with Closure Units in 2013 (by NERC Region)[a]

NERC Region	Base Case Facilities	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closures	% Change	Closures	% Change
ECAR	99	0	0.0%	1	1.0%
ERCOT	51	0	0.0%	1	2.0%
FRCC	30	0	0.0%	0	0.0%
MAAC	41	0	0.0%	0	0.0%
MAIN	47	0	0.0%	0	0.0%
MAPP	42	0	0.0%	0	0.0%
NPCC	54	-1	-1.9%	0	0.0%
SERC	95	0	0.0%	0	0.0%
SPP	32	0	0.0%	1	3.1%
WSCC	33	2	6.0%	2	6.0%
Total	**525**	**1**	**0.2%**	**5**	**1.0%**

a Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Table B8-13: Capacity of Closure Units by 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Phase II Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closure Capacity	% of Total	Closure Capacity	% of Total
ECAR	78,680	0	0.0%	2,060	2.6%
ERCOT	42,330	0	0.0%	420	1.0%
FRCC	24,460	0	0.0%	0	0.0%
MAAC	30,310	0	0.0%	0	0.0%
MAIN	33,650	0	0.0%	490	1.5%
MAPP	14,900	0	0.0%	0	0.0%
NPCC	36,360	650	1.8%	720	2.0%
SERC	100,780	0	0.0%	0	0.0%
SPP	19,990	0	0.0%	20	0.1%
WSCC	30,110	2,170	7.2%	2,170	7.2%
Total	**411,570**	**2,820**	**0.7%**	**5,880**	**1.4%**

a Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Table B8-12 shows that two regions, NPCC and WSCC, experience a change in closures of Phase II facilities as a result of this option. One fewer facility would close in NPCC in comparison to the base case: two facilities that would have retired in the baseline remain operational under the analyzed option while another, with higher post-compliance production costs, would close. As the total capacity of the single facility expected to close under this option exceeds that of the two avoided closures, NPCC experiences a net reduction of 650 MW, or 1.8 percent of baseline Phase II capacity . The largest reduction in baseline Phase II capacity occurs in WSCC where one large nuclear and one small oil/gas facility, accounting for 7.2 percent of total base case Phase II capacity, closes under this option.

All cooling towers option: A total of five Phase II facilities from four NERC regions (ECAR, ERCOT, SPP and WSCC) accounting for 5,880 MW, or 1.4 percent of base case Phase II capacity, closes under this option. The largest closures would occur in WSCC and ECAR where 7.2 percent (2,170 MW) and 2.6 percent (2,060 MW) respectively of base case Phase II capacity would close.

b. Phase II non-dispatch facilities

Table B8-14 presents the total base case capacity, as well as total non-dispatched capacity under the base case and both alternative options by NERC region. For each of these three scenarios total non-dispatched capacity is expressed as a percentage of total base case capacity in the region. The difference between total non-dispatched capacity as a percentage of total base case capacity for each of the regulatory options and total base case non-dispatched capacity as a percentage of total base case capacity is calculated and presented in bold.

Table B8-14: Capacity of Non-Dispatch Facilities in 2013 (MW; by NERC Region)[a]

NERC Region	Total Base Case Capacity	Base Case Capacity of Non-Dispatch Facilities	Non-Dispatch Capacity as a % of Total	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Non-Dispatch Capacity	Non-Dispatch Capacity as a % of Total	Difference	Non-Dispatch Capacity	Non-Dispatch Capacity as a % of Total	Difference
ECAR	78,680	190	0.2%	190	0.2%	**0.0%**	190	0.2%	**0.0%**
ERCOT	42,330	5,830	13.8%	5,790	13.7%	**-0.1%**	5,740	13.6%	**-0.2%**
FRCC	24,460	7,800	31.9%	6,540	26.7%	**-5.2%**	7,700	31.5%	**-0.4%**
MAAC	30,310	2,070	6.8%	2,070	6.8%	**0.0%**	2,070	6.8%	**0.0%**
MAIN	33,650	2,760	8.2%	2,760	8.2%	**0.0%**	2,760	8.2%	**0.0%**
MAPP	14,900	330	2.2%	330	2.2%	**0.0%**	320	2.1%	**-0.1%**
NPCC	36,360	7,690	21.2%	7,570	20.8%	**-0.3%**	6,980	19.2%	**-2.0%**
SERC	100,780	5,060	5.0%	6,100	6.1%	**1.0%**	6,750	6.7%	**1.7%**
SPP	19,990	2,130	10.7%	2,130	10.7%	**0.0%**	2,080	10.4%	**-0.3%**
WSCC	30,110	4,290	14.2%	5,390	17.9%	**3.7%**	5,740	19.1%	**4.8%**
Total	**411,570**	**38,150**	**9.3%**	**38,870**	**9.4%**	**0.2%**	**40,330**	**9.8%**	**0.5%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, non-dispatched capacity as a percentage of base case capacity increases by 0.2 percent under this option. By far the largest increase in this metric occurs in WSCC (3.7 percent). This result suggests that Phase II facilities in this region become less competitive and are dispatched less frequently as a result of this option. The increase in the variable production costs of Phase II facilities shown in Table B8-18 supports this finding. The largest decrease in non-dispatched capacity as a percentage of base case capacity occurs in FRCC (5.2 percent). This reduction implies that a *higher* percentage of Phase II capacity would be dispatched under this option relative to the base case, despite the increased production cost of these facilities (see Table B8-18). This difference is due to one large oil/gas facility that is not dispatched under the baseline, but is dispatched under the option.

All cooling towers option: Overall, non-dispatched capacity as a percentage of base case capacity increases by 0.5 percent under this option. As was the case under the waterbody/capacity-based option, the largest increase occurs in WSCC (4.8 percent) due most likely to the increased variable production costs of Phase II facilities in this region (see Table B8-18). The largest decrease in non-dispatched capacity as a percentage of base case capacity occurs in NPCC (2.0 percent).

c. Phase II capacity

Table B8-15 presents the total Phase II capacity under the base case and each of the alternative regulatory options by NERC region. Total Phase II capacity associated with each option is expressed as a percentage of total base case Phase II capacity.

Table B8-15: Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity	% Change	Capacity	% Change
ECAR	78,680	78,680	0.0%	75,690	-3.8%
ERCOT	42,330	42,270	-0.1%	41,400	-2.2%
FRCC	24,460	24,330	-0.5%	24,200	-1.1%
MAAC	30,310	30,180	-0.4%	30,030	-0.9%
MAIN	33,650	33,650	0.0%	32,790	-2.6%
MAPP	14,900	14,900	0.0%	14,700	-1.3%
NPCC	36,360	35,220	-3.1%	34,500	-5.1%
SERC	100,780	100,680	-0.1%	99,540	-1.2%
SPP	19,990	19,990	0.0%	19,840	-0.8%
WSCC	30,110	27,540	-8.5%	26,280	-12.7%
Total	**411,570**	**407,440**	**-1.0%**	**398,970**	**-3.1%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, this option results in a reduction in Phase II capacity of 4,130 MW, or 1.0 percent. A majority of the decrease (2,820 MW) is due to closures. The residual 1,310 MW is due to energy penalties. Capacity decreases in six NERC regions, while remaining unchanged the other four. The two largest reductions in this metric occur in WSCC and NPCC, which experience reductions of 8.5 percent and 3.1 percent of base case capacity, respectively. In both regions, the majority of this reduction in available capacity is associated with the economic closure of existing Phase II facilities (see Table B8-13).

All cooling towers option: Overall, there is a reduction in available capacity of approximately 12,600 MW, or 3.1 percent of total base case capacity. Of the 12,600 MW, 5,880 (47 percent) are due to closures. The residual 6,720 MW is due to energy penalties. The three largest reductions occur in WSCC (12.7 percent), NPCC (5.1 percent), and ECAR (3.8 percent). As was the case under the waterbody/capacity-based option, the majority of this reduction in available capacity is associated with the economic closure of existing Phase II facilities (see Table B8-13).

d. Phase II generation

Table B8-16 presents the base case generation, and total generation under each of the two alternative options and the percent change in generation between the base case and each option by NERC region.

Table B8-16: Generation in 2013 (Million MWh; by NERC Region)[a]

NERC Region	Base Case Generation	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Generation	% Change	Generation	% Change
ECAR	521	521	0.0%	510	-2.1%
ERCOT	153	153	0.0%	147	-4.1%
FRCC	80	78	-3.3%	77	-4.1%
MAAC	171	169	-1.3%	167	-2.3%
MAIN	216	216	0.0%	211	-2.5%
MAPP	105	105	0.0%	104	-1.3%
NPCC	158	149	-5.5%	142	-10.1%
SERC	630	630	-0.1%	621	-1.5%
SPP	110	110	0.0%	109	-1.2%
WSCC	145	118	-18.8%	100	-30.9%
Total	**2,290**	**2,249**	**-1.8%**	**2,188**	**-4.5%**

[a] Percent changes have been rounded to the nearest 10[th].

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, generation decreases by 1.8 percent as a result of this option. The two largest reductions are experienced in WSCC (18.8 percent) and NPCC (5.5 percent). These decreases in generation are most likely attributable to the reductions in capacity resulting from closures and the energy penalty, and the increased variable production costs of non-closure Phase II facilities that occur in these two regions under this option (see Tables B8-15 and B8-18).

All cooling towers option: Overall, this option results in a 4.5 percent decrease in generation. While every region experiences a reduction in this metric, the two largest reductions occur in WSCC (30.9 percent) and NPCC (10.1 percent). As was the case under the waterbody/capacity-based option, these reductions are likely due to reductions in available capacity and increased production costs of non-closure Phase II facilities (see Tables B8-15 and B8-18).

e. Phase II revenues

Table B8-17 presents total Phase II revenues under the base case and each of the two alternative regulatory options by NERC region. Revenues associated with each option are also expressed as a percentage of total base case revenues.

Table B8-17: Revenues in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Revenues	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Revenues	% Change	Revenues	% Change
ECAR	16,370	16,370	0.0%	16,200	-1.0%
ERCOT	5,440	5,430	-0.2%	5,260	-3.3%
FRCC	3,240	3,170	-2.2%	3,140	-3.1%
MAAC	6,070	6,020	-0.8%	5,990	-1.3%
MAIN	6,730	6,730	0.0%	6,610	-1.8%
MAPP	3,020	3,020	0.0%	3,010	-0.3%
NPCC	5,980	5,790	-3.2%	5,600	-6.4%
SERC	20,190	20,180	0.0%	19,990	-1.0%
SPP	3,450	3,450	0.0%	3,420	-0.9%
WSCC	4,880	4,040	-17.2%	3,510	-28.1%
Total	**75,370**	**74,200**	**-1.6%**	**72,730**	**-3.5%**

[a] Revenues have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, there is a reduction in revenues of 1.6 percent associated with this option. Revenues decrease in five NERC regions and remain unchanged in the others. The two largest reductions in revenues occur in WSCC (17.2 percent) and NPCC (3.2 percent). The reduction in generation and price shown in Tables B8-16 and B8-10, respectively, are likely the principal cause for the reductions in revenues in these regions.

All cooling towers option: Every NERC region experiences a reduction in revenues as a result of this option. In aggregate, these reductions account for 3.5 percent of base case revenues. As was the case under the waterbody/capacity option, the two largest reductions in revenues occur in WSCC (28.1 percent) and NPCC (6.4 percent), the two regions with the largest reductions in generation under this option (see Table B8-16). The reductions in generation and price shown in Tables B8-16 and B8-10, respectively, are the likely cause for the reductions in revenues in these regions.

f. Phase II variable production costs

Table B8-18 presents the base case variable production costs per MWh of generation, as well as variable production costs under the each of the two alternative options and the percent change in variable production costs between the base case and each of the two alternative options by NERC region.

Table B8-18: Variable Production Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Production Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Production Costs	% Change	Production Costs	% Change
ECAR	11.59	11.58	-0.1%	11.75	1.4%
ERCOT	15.67	15.68	0.0%	15.60	-0.5%
FRCC	15.21	15.32	0.7%	15.32	0.8%
MAAC	11.43	11.43	0.0%	11.32	-1.0%
MAIN	11.30	11.30	0.0%	11.46	1.4%
MAPP	11.04	11.04	0.0%	11.19	1.3%
NPCC	18.43	18.39	-0.2%	18.38	-0.3%
SERC	11.16	11.16	0.0%	11.27	1.0%
SPP	12.13	12.13	0.0%	12.15	0.1%
WSCC	16.83	17.48	3.9%	17.26	2.6%

[a] Percent changes have been rounded to the nearest 10^{th}.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Four NERC regions experience a change in variable production costs per MWh of generation under this option. The largest increase occurs in WSCC (3.9 percent). This increase is most likely attributable to the increase in production costs of non-closure Phase II facilities, and the economic closure of Phase II capacity. The majority of the 2,170 MW of closed capacity in the WSCC region listed in Table B8-13, is relatively low cost nuclear capacity. The elimination of low cost nuclear capacity from the group of Phase II facilities in this region increases the average variable production cost for the group in this region. In NPCC, the economic closure of relatively high cost oil and gas fired capacity is most likely responsible for the 0.2 percent reduction in variable production costs of Phase II facilities.

All cooling towers option: Seven NERC regions experience an increase in variable production costs under this option while the remaining three see a decrease in this metric. As was the case under the waterbody/capacity-based option, data presented in Table B8-13 suggest the economic closure of low cost nuclear capacity in WSCC is most likely responsible for the largest increase in variable production costs per MWh (2.6 percent). The largest decrease in variable production costs would occur in ERCOT, at 0.5 percent.

g. Phase II fuel costs

Table B8-19 presents the base case fuel costs as well as fuel costs under the two alternative options and the percent change in fuel costs between the base case and the two options by NERC region.

Table B8-19: Fuel Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Fuel Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Fuel Costs	% Change	Fuel Costs	% Change
ECAR	9.13	9.13	-0.1%	9.29	1.7%
ERCOT	12.89	12.89	0.1%	12.82	-0.5%
FRCC	12.80	12.92	0.9%	12.96	1.2%
MAAC	9.28	9.27	-0.1%	9.18	-1.1%
MAIN	9.06	9.06	0.0%	9.22	1.8%
MAPP	8.99	8.99	0.0%	9.13	1.5%
NPCC	16.73	16.67	-0.3%	16.64	-0.6%
SERC	9.01	9.01	0.0%	9.12	1.3%
SPP	9.90	9.90	0.0%	9.91	0.1%
WSCC	14.72	15.35	4.3%	14.97	1.7%

[a] Percent changes have been rounded to the nearest 10^{th}.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Six of the ten NERC regions experience a change in fuel cost per MWh of generation as a result of this option. This increase occurs in part due to the nuclear facility closure. Since total regional demand for generation does not change (Table B8-6), new and repowered combined cycle and combustion turbine capacity comes on-line (Tables B8-4 and B8-5). This capacity, and its subsequent generation, increases the demand on the fuel supply, increasing the cost of fuel in the region. The largest increase in fuel costs occurs in WSCC (4.3 percent) while the largest decrease occurs in NPCC (0.3 percent).

All cooling towers option: Fuel cost per MWh of generation changes in each of the ten NERC regions under this option. The largest increases in fuel cost per MWh of generation occur in MAIN (1.8 percent), ECAR (1.7 percent), and WSCC (1.7 percent). The largest decrease in fuel costs occurs in MAAC, (at 1.1 percent).

B8-3.2 Individual Phase II Facilities

In addition to effects of the two alternative options in the group of Phase II facilities, there may be shifts in economic performance among individual facilities subject to section 316(b) regulation. To assess potential distributional effects, EPA analyzed facility-specific changes in net generation, production costs, capacity utilization, revenue, and operating income. For each measure, EPA determined the number of Phase II facilities that experience an increase or a reduction within three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more. Excluded from this analysis were facilities experiencing significant structural changes as a result of a policy option, including partial or full closures, avoided closures, or repowering.

Tables B8-20 and B8-21 present the total number of Phase II facilities with different degrees of change in each of these measures under the waterbody/capacity-based and all cooling towers options.

Table B8-20: Operational Changes at Phase II Facilities from the Waterbody/Capacity-Based Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	7	17	21	4	4	9	444
Change in Variable Production Costs	6	5	1	13	16	3	380
Change in Capacity Utilization	10	7	12	7	3	5	462
Change in Total Revenue	57	43	17	48	15	20	306
Change in Operating Income	75	42	10	46	15	22	296

a For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

b Of the 540 Phase II facilities, 34 would experience a significant structural change as a result of the rule, and are therefore excluded from this analysis. Of the remaining 506 facilities, 82 facilities had zero generation in either the base case or post compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 424 instead of 506 for this measure.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-20 indicates that the majority of Phase II facilities do not experience changes in generation, production costs, or capacity utilization due to compliance with the waterbody/capacity-based option. Of those facilities with changes in post-compliance generation and capacity utilization, most experience decreases in these measures. In addition, while approximately 40 percent of Phase II facilities experience an increase or decrease in revenues and/or operating income, the magnitude of such changes are small.

Table B8-21: Operational Changes at Phase II Facilities from the All Cooling Towers Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	18	251	53	3	4	22	151
Change in Variable Production Costs	16	12	4	64	257	17	51
Change in Capacity Utilization	15	25	25	8	12	15	402
Change in Total Revenue	154	121	55	88	39	35	10
Change in Operating Income	118	160	50	83	47	29	15

a For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

B Of the 540 Phase II facilities, 38 would experience a significant structural change as a result of the rule, and are therefore excluded from this analysis. Of the remaining 502 facilities, 81 facilities had zero generation in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 421 instead of 502 for this measure.

Source: IPM analysis: model runs for Section 316(b) base case and all cooling towers option.

Table B8-21 indicates that under the all cooling towers option, more facilities would experience changes in their operations and economic performance than under the waterbody/capacity-based option. For example, 322 out of 502 facilities, or 64 percent, experience a reduction in generation.[6] In addition, 328 facilities experience a reduction in operating income while 338 facilities see their production cost per MWh increase. However, some facilities benefit from regulation under this option: 162 facilities experience an increase in revenues and 159 experience an increase in operating income.

B8-4 Uncertainties and Limitations

EPA has identified uncertainties and limitations associated with the electricity market model analysis of the waterbody/capacity-based option and the all cooling towers option. These uncertainties and limitations are discussed below.

Capacity Utilization Assumption Used in IPM Analysis: EPA estimated compliance responses for in-scope facilities and developed compliance costs using capacity utilization rates from EIA data sources (average 1995-1999 generation from Form EIA-906; average 1995-1999 capacity from Forms EIA-860A and 860B). However, this capacity utilization rate does not always match the rate projected by the IPM for run year 2008. A discrepancy between the rates from the two data sources may lead to an overestimation or underestimation of economic impacts and/or energy effects in the market model analysis using the IPM.

Facilities with a capacity utilization rate of less than 15 percent would be subject to less stringent compliance requirements under the proposed rule and the two analyzed alternative regulatory options, partially because stringent compliance requirements, and high compliance costs, are not required if the facility is used on an intermittent basis only. Economically, a low utilization rate means lower revenues as the facility generates and sells less electricity (this fact is somewhat mitigated by the presence of capacity revenues in the IPM). Using a capacity utilization rate from EIA sources could introduce two types of errors in the economic impact analysis based on the IPM. These errors arise from the following two scenarios: (1) A facility was costed with less stringent compliance requirements because its EIA capacity utilization rate is less than 15 percent. However, its IPM rate is greater than 15 percent. Such a facility is undercosted relative to its economic condition modeled by the IPM. (2) A facility was costed with the full compliance requirements because its EIA capacity utilization rate is greater than 15 percent. However, its IPM rate is less than 15 percent. Such a facility is overcosted relative to its economic condition modeled by the IPM.

To assess the potential uncertainty associated with using a capacity utilization rate that does not always match the assumption of the IPM, EPA compared the rates between the EIA data sources and the IPM. This comparison showed that 56 out of the 540 in-scope facilities modeled by the IPM would fall under the 15 percent capacity utilization threshold based on the EIA data. Of these 56 facilities, 21 exceed the 15 percent threshold based on IPM data. These 21 facilities, or 3.9 percent of all facilities, have potentially been undercosted. Conversely, 112 facilities would fall under the 15 percent capacity utilization threshold based on the IPM data. Of these 112 facilities, 77 exceed the 15 percent threshold based on EIA data. These 77 facilities, or 14.3 percent of all facilities, have potentially been overcosted. Table B8-22 summarizes the differences between the EIA and IPM capacity utilization rates.

Table B8-22: Comparison of EIA and IPM Capacity Utilization Rates

Capacity Utilization < 15% in both EIA and IPM	407
Capacity Utilization < 15% in IPM, but > 15 % in EIA	77
Capacity Utilization < 15% in EIA, but > 15 % in IPM	21
Capacity Utilization > 15% in both EIA and IPM	35
Total	540

Source: *IPM analysis: model run for Section 316(b) Base Case; U.S. DOE, 1999a; U.S. DOE, 1999b.*

The largest cost differential is associated with facilities that would or would not be costed with a recirculating cooling tower based on their capacity utilization. EPA therefore compared the number of facilities that would be costed with a cooling

[6] As explained earlier, facilities with significant status changes (including baseline closures, avoided closures, and facilities that repower) are excluded from this comparison.

tower under the waterbody/capacity-based option, using the two respective capacity utilization rates. With the EIA rate, EPA determined that of 60 facilities meeting the criteria that would require a cooling tower, 52 have a capacity utilization rate of greater than 15 percent. For the analysis presented in this chapter, these 52 facilities were costed with a cooling tower. However, with the IPM capacity utilization rate, 16 of these 52 facilities would not have been costed with a cooling tower. Conversely, of the eight facilities that were not costed with a cooling tower based on the 15 percent threshold using the EIA rate, two facilities would have been costed with a cooling tower, had the IPM rate been used. The differential between the two utilization rates is therefore 14 cooling towers (16 minus 2).

Based on these analyses, EPA concludes that a capacity utilization rate using EIA data would likely overstate the total cost of the proposed rule and the alternative regulatory options, and therefore lead to a conservative estimate of economic impacts.

Data Input Errors: Due to a costing error, the compliance costs of one facility located in MAAC were understated in the IPM analysis of the waterbody/capacity-based option. The facility should have been costed with a fish handling and return system and annualized compliance cost of approximately $1.2 million. The IPM input represented no compliance technology and annualized compliance costs of less than $100,000. As a result of the understatement of compliance costs for this facility, the IPM analysis may have underestimated production costs in this region, thereby potentially increasing the dispatch of this facility.

Modeling Issues: EPA identified three modeling issues that could potentially impact the magnitude of the results of the IPM analysis. These issues are associated with: (1) repowering, (2) downtime associated with cooling tower connection, and (3) application of the energy penalty. ***Repowering:*** For the section 316(b) analysis, EPA is not using the IPM function that allows the model to pick among a set of compliance responses. As a result, there is no iterative process that would adjust the compliance response, and as a result the cost of compliance, if a facility chooses to repower. In the IPM, some oil/gas facilities repower to combined-cycle prime movers. This would often lead to a reduction in intake flow and potentially to less stringent compliance requirements or to lower costs (for costs that are a function of intake flow). Not allowing the model to adjust the compliance response or cost would lead to a conservative estimate of compliance costs and potential economic impacts from the proposed rule and the alternative regulatory options analyzed with the IPM. ***Downtime associated with cooling tower connection:*** EPA assumes that it would take one month of generator down-time to install and connect a recirculating cooling tower. As a result of the current specification of seasons in the IPM, it is not possible to model the downtime as a 100 percent outage during one month. Instead, the downtime is spread over the entire winter season of seven months and is represented as if a 1/7th of the facility were down for a period of seven months. It is unclear how this current modeling constraint would impact the results of the model. It is possible that short term impacts that would lead to temporary price increases would be understated, leading to an overall lower average price over the model run year. ***Application of the energy penalty:*** Due to a programming error in the model, which could not be resolved in time for the proposed rule, the energy penalty for some facilities was incorrectly applied. This problem affected one out of 52 facilities for the waterbody/capacity-based option and nine out of 416 facilities for the all cooling towers option. As a result of this omission, regional energy effects and impacts on the facilities in question may have been understated.

REFERENCES

U.S. Department of Energy (U.S. DOE). 1999a. *Form EIA-860A (1999). Annual Electric Generator Report – Utility.*

U.S. Department of Energy (U.S. DOE). 1999b. *Form EIA-860B (1999). Annual Electric Generator Report – Nonutility*.

U.S. Environmental Protection Agency (U.S. EPA). 2002. *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model*. EPA 430/R-02-004. March 2002.

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Appendix to Chapter B8

Appendix Contents

EPA conducted model runs based on two different electricity demand assumptions: (1) a case using EPA's electricity demand assumptions and (2) a case using Annual Energy Outlook (AEO) electricity demand assumptions.[7] The analyses presented in this appendix are based on using Annual Energy Outlook (AEO) electricity demand assumptions; the main body of Chapter B8 presented the results using EPA's assumptions. Under the EPA assumption, the demand for electricity is based on the AEO 2001 forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The AEO electricity demand assumption, on the other hand, utilizes the AEO 2001 without adjustment. The remainder of this appendix presents the results of the waterbody/capacity-based option under the AEO electricity demand assumptions, and a comparison of the differences in results between the AEO based assumptions and the EPA based assumptions.

B8-A1 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of section 316(b) regulation under the two demand assumptions presented above. Market level impacts associated with each of the alternative assumptions are assessed using seven impact measures developed from IPM output for model run year 2013.[8] A detailed description of each of the impact measures presented below can be found in Section B3-3.1 of *Chapter B3: Electricity Market Model Analysis*.

[7] The Annual Energy Outlook reflects all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990.

[8] The IPM model simulates electricity market function for a period of 25 years. Model output is provided for five user-specified model run years. EPA selected three run years to provide output across the ten year compliance period for the rule. Analyses of regulatory options are based on output for model run years that reflect a scenario in which all facilities are operating in their post-compliance condition. Options requiring the installation of cooling towers are analyzed using output from model run year 2013.

Table B8-A-1: National Capacity of Closure Units in 2013 (MW; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	133,020	0	0.0%	0.0%	**0.0%**
ERCOT	86,610	0	0.0%	0.0%	**0.0%**
FRCC	57,080	0	0.0%	0.0%	**0.0%**
MAAC	70,530	1,110	1.6%	0.0%	**1.6%**
MAIN	66,420	0	0.0%	0.0%	**0.0%**
MAPP	39,700	0	0.0%	0.0%	**0.0%**
NPCC	79,360	460	0.6%	1.1%	**-0.5%**
SERC	220,570	0	0.0%	0.0%	**0.0%**
SPP	55,710	0	0.0%	0.0%	**0.0%**
WSCC	186,000	0	0.0%	1.3%	**-1.3%**
Total	**995,000**	**1,570**	**0.2%**	**0.3%**	**-0.1%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-2: National Domestic Capacity in 2013 (MW; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	133,020	133,020	0.0%	0.1%	**-0.1%**
ERCOT	86,610	86,550	-0.1%	-0.1%	**0.0%**
FRCC	57,080	56,960	-0.2%	-0.3%	**0.1%**
MAAC	70,530	70,420	-0.2%	-0.2%	**0.0%**
MAIN	66,420	66,240	-0.3%	0.0%	**-0.3%**
MAPP	39,700	39,700	0.0%	-0.1%	**0.1%**
NPCC	79,360	79,070	-0.4%	-0.3%	**-0.1%**
SERC	220,570	220,710	0.1%	-0.1%	**0.2%**
SPP	55,710	55,710	0.0%	0.0%	**0.0%**
WSCC	186,000	185,860	-0.1%	-0.1%	**0.0%**
Total	**995,000**	**994,240**	**-0.1%**	**-0.1%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-3: National Domestic Capacity Additions in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions						% Change from EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case Total Capacity	Base Case Additions	% Change	Post-Compliance Additions	% Change	Difference		
ECAR	133,020	22,990	17.3%	22,990	17.3%	**0.0%**	**0.1%**	**-0.1%**
ERCOT	86,610	11,320	13.1%	11,310	13.1%	**0.0%**	**0.0%**	**0.0%**
FRCC	57,080	17,840	31.3%	17,860	31.3%	**0.0%**	**0.0%**	**0.0%**
MAAC	70,530	11,450	16.2%	12,580	17.8%	**1.6%**	**0.1%**	**1.5%**
MAIN	66,420	15,300	23.0%	15,120	22.8%	**-0.3%**	**0.0%**	**-0.3%**
MAPP	39,700	7,020	17.7%	7,020	17.7%	**0.0%**	**-0.1%**	**0.1%**
NPCC	79,360	11,490	14.5%	11,930	15.0%	**0.6%**	**1.4%**	**-0.8%**
SERC	220,570	56,020	25.4%	56,260	25.5%	**0.1%**	**-0.1%**	**0.2%**
SPP	55,710	6,750	12.1%	6,750	12.1%	**0.0%**	**0.0%**	**0.0%**
WSCC	186,000	25,560	13.7%	25,460	13.7%	**-0.1%**	**0.7%**	**-0.8%**
Total	**995,000**	**185,740**	**18.7%**	**187,280**	**18.8%**	**0.2%**	**0.2%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-4: National Repowering Capacity in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions						% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case Total Capacity	Base Case Repowered Capacity	Repowering as a % of Total Base Case Capacity	Post-Compliance Repowering	Repowering as a % of Total Base Case Capacity	Difference		
ECAR	133,020	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
ERCOT	86,610	5,490	6.3%	5,510	0.4%	**-5.9%**	**0.0%**	**-5.9%**
FRCC	57,080	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
MAAC	70,530	1,660	2.4%	1,640	-1.2%	**-3.6%**	**0.0%**	**-3.6%**
MAIN	66,420	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
MAPP	39,700	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
NPCC	79,360	7,960	10.0%	7,730	-2.9%	**-12.9%**	**-0.8%**	**-12.1%**
SERC	220,570	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
SPP	55,710	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
WSCC	186,000	7,550	4.1%	7,770	2.9%	**-1.2%**	**1.1%**	**-2.3%**
Total	**995,000**	**22,660**	**2.3%**	**22,650**	**0.0%**	**-2.3%**	**0.2%**	**-2.5%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-5: National Generation in 2013 (million MWh; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	703	704	0.2%	0.0%	**0.2%**
ERCOT	389	389	0.0%	0.0%	**0.0%**
FRCC	218	218	0.0%	0.0%	**0.0%**
MAAC	311	310	-0.3%	-0.2%	**-0.1%**
MAIN	306	306	-0.1%	0.3%	**-0.4%**
MAPP	201	201	0.0%	0.0%	**0.0%**
NPCC	312	312	0.2%	-0.1%	**0.3%**
SERC	1,072	1,071	-0.1%	0.0%	**-0.1%**
SPP	244	244	0.0%	0.0%	**0.0%**
WSCC	849	849	0.0%	0.0%	**0.0%**
Total	**4,604**	**4,604**	**0.0%**	**0.0%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-6: National Revenues in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	24,750	24,790	0.2%	0.0%	**0.2%**
ERCOT	13,480	13,470	-0.1%	0.0%	**-0.1%**
FRCC	8,890	8,910	0.2%	-0.3%	**0.5%**
MAAC	12,280	12,270	-0.1%	-0.2%	**0.1%**
MAIN	11,020	11,010	-0.1%	0.2%	**-0.3%**
MAPP	6,680	6,680	0.0%	0.0%	**0.0%**
NPCC	12,330	13,070	6.0%	2.4%	**3.6%**
SERC	38,060	38,050	0.0%	0.0%	**0.0%**
SPP	8,660	8,660	0.0%	0.0%	**0.0%**
WSCC	28,490	28,490	0.0%	0.2%	**-0.2%**
Total	**164,640**	**165,400**	**0.5%**	**0.2%**	**0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-7: National Variable Production Costs/MWh Generation in 2013 ($2001; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	12.51	12.53	0.1%	0.0%	**0.1%**
ERCOT	17.52	17.52	0.0%	0.0%	**0.0%**
FRCC	18.93	19.00	0.4%	0.4%	**0.0%**
MAAC	13.70	14.08	2.8%	0.7%	**2.1%**
MAIN	12.81	12.79	-0.1%	0.2%	**-0.3%**
MAPP	11.79	11.79	-0.1%	0.0%	**-0.1%**
NPCC	18.25	18.33	0.4%	0.5%	**-0.1%**
SERC	13.49	13.50	0.1%	0.1%	**0.0%**
SPP	14.19	14.19	0.0%	0.0%	**0.0%**
WSCC	12.19	12.20	0.1%	1.9%	**-1.8%**
Total	**13.85**	**13.89**	**0.3%**	**0.5%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-8: National Fuel Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	10.11	10.13	0.2%	-0.1%	**0.3%**
ERCOT	15.59	15.59	0.0%	0.0%	**0.0%**
FRCC	17.04	17.12	0.4%	0.6%	**-0.2%**
MAAC	11.68	12.08	3.4%	0.8%	**2.6%**
MAIN	10.80	10.78	-0.2%	0.3%	**-0.5%**
MAPP	9.79	9.78	-0.1%	0.0%	**-0.1%**
NPCC	16.93	17.01	0.4%	0.6%	**-0.2%**
SERC	11.68	11.68	0.1%	0.1%	**0.0%**
SPP	12.40	12.40	0.0%	0.0%	**0.0%**
WSCC	10.72	10.72	0.1%	2.5%	**-2.4%**
Total	**12.01**	**12.05**	**0.3%**	**0.6%**	**-0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-9: Energy Prices in 2013 ($2001 per KWh; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	24.53	24.52	0.0%	0.0%	**0.0%**
ERCOT	26.77	26.81	0.1%	0.0%	**0.1%**
FRCC	29.66	29.58	-0.3%	0.5%	**-0.8%**
MAAC	27.94	27.98	0.1%	0.6%	**-0.5%**
MAIN	23.83	23.82	0.0%	0.1%	**-0.1%**
MAPP	22.37	22.37	0.0%	0.0%	**0.0%**
NPCC	30.68	30.67	0.0%	-0.3%	**0.3%**
SERC	25.46	25.46	0.0%	0.0%	**0.0%**
SPP	24.33	24.34	0.0%	0.0%	**0.0%**
WSCC	26.09	26.10	0.0%	-0.1%	**0.1%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-10: Capacity Prices in 2013 ($2001 per KW per year; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	56.54	56.63	0.2%	-0.2%	**0.4%**
ERCOT	35.56	35.35	-0.6%	-0.2%	**-0.4%**
FRCC	42.33	43.13	1.9%	-2.0%	**3.9%**
MAAC	51.11	51.30	0.4%	-1.5%	**1.9%**
MAIN	56.15	56.16	0.0%	-0.1%	**0.1%**
MAPP	55.58	55.58	0.0%	-0.1%	**0.1%**
NPCC	37.80	47.65	26.0%	13.2%	**12.8%**
SERC	48.92	48.90	0.0%	0.0%	**0.0%**
SPP	48.94	48.94	0.0%	0.0%	**0.0%**
WSCC	37.04	37.06	0.1%	2.0%	**-1.9%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

B8-A2 Phase II Facility Analysis

EPA used the IPM results to analyze two potential facility-level impacts of the waterbody/capacity-based option: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which is not subject to this rule.

B8-A2.1 Group of Phase II Facilities

This section presents the analysis of the potential impacts of the waterbody/capacity-based option on the group of Phase II facilities. Section B3-3.2 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of the seven impact measures developed using IPM output from model run year 2013 and used to assess potential changes in the economic and operational characteristics of this group of facilities.

Table B8-A-11: Number of Facilities with Closure Units in 2013 (by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	99	0	0.0%	0.0%	**0.0%**
ERCOT	51	0	0.0%	0.0%	**0.0%**
FRCC	30	0	0.0%	0.0%	**0.0%**
MAAC	41	1	2.4%	0.0%	**2.4%**
MAIN	47	0	0.0%	0.0%	**0.0%**
MAPP	42	0	0.0%	0.0%	**0.0%**
NPCC	57	(1)	-1.8%	-1.9%	**0.1%**
SERC	95	0	0.0%	0.0%	**0.0%**
SPP	32	0	0.0%	0.0%	**0.0%**
WSCC	34	0	0.0%	6.0%	**-6.0%**
Total	**528**	**0**	**0.0%**	**0.2%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-12: Capacity of Closure Units in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	78,660	0	0.0%	0.0%	**0.0%**
ERCOT	43,460	0	0.0%	0.0%	**0.0%**
FRCC	24,440	0	0.0%	0.0%	**0.0%**
MAAC	31,410	1,110	3.5%	0.0%	**3.5%**
MAIN	34,140	0	0.0%	0.0%	**0.0%**
MAPP	14,890	0	0.0%	0.0%	**0.0%**
NPCC	37,290	930	2.5%	1.8%	**0.7%**
SERC	100,780	0	0.0%	0.0%	**0.0%**
SPP	19,990	0	0.0%	0.0%	**0.0%**
WSCC	30,950	0	0.0%	7.2%	**-7.2%**
Total	**416,010**	**2,040**	**0.5%**	**0.7%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-13: Capacity of Non-Dispatched Facilities in 2013 (MW; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	190	190	0.0%	0.0%	**0.0%**
ERCOT	6,330	5,790	-8.5%	-0.7%	**-7.8%**
FRCC	7,800	7,760	-0.5%	-16.2%	**15.7%**
MAAC	2,070	2,070	0.0%	0.0%	**0.0%**
MAIN	2,760	2,760	0.0%	0.0%	**0.0%**
MAPP	330	330	0.0%	0.0%	**0.0%**
NPCC	5,820	7,980	37.1%	-1.6%	**38.7%**
SERC	6,960	6,930	-0.4%	20.6%	**-21.0%**
SPP	2,130	2,130	0.0%	0.0%	**0.0%**
WSCC	5,860	7,280	24.2%	25.6%	**-1.4%**
Total	**40,250**	**43,220**	**7.4%**	**1.9%**	**5.5%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-14: Capacity in 2013 (MW; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	78,660	78,660	0.0%	0.0%	**0.0%**
ERCOT	43,460	43,420	-0.1%	-0.1%	**0.0%**
FRCC	24,440	24,300	-0.6%	-0.5%	**-0.1%**
MAAC	31,410	30,180	-3.9%	-0.4%	**-3.5%**
MAIN	34,140	34,140	0.0%	0.0%	**0.0%**
MAPP	14,890	14,890	0.0%	0.0%	**0.0%**
NPCC	37,290	36,040	-3.4%	-3.1%	**-0.3%**
SERC	100,780	99,050	-1.7%	-0.1%	**-1.6%**
SPP	19,990	19,990	0.0%	0.0%	**0.0%**
WSCC	30,950	29,790	-3.7%	-8.5%	**4.8%**
Total	**416,010**	**410,460**	**-1.3%**	**-1.0%**	**-0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-15: Generation in 2013 (MWh; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	533	536	0.6%	0.0%	**0.6%**
ERCOT	162	171	5.8%	0.0%	**5.8%**
FRCC	80	106	32.8%	0.0%	**32.8%**
MAAC	179	155	-13.3%	0.0%	**-13.3%**
MAIN	221	243	10.2%	0.0%	**10.2%**
MAPP	107	129	21.1%	0.0%	**21.1%**
NPCC	161	174	8.1%	-6.3%	**14.4%**
SERC	630	545	-13.4%	0.0%	**-13.4%**
SPP	109	117	7.6%	0.0%	**7.6%**
WSCC	140	114	-18.6%	-14.3%	**-4.3%**
Total	**2,321**	**2,291**	**-1.3%**	**-1.3%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-16: Revenues in 2013 ($2001 Million; by NERC Region)					
NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	17,320	17,600	1.6%	0.0%	**1.6%**
ERCOT	5,850	6,250	6.8%	-0.2%	**7.0%**
FRCC	3,360	4,180	24.4%	-2.2%	**26.6%**
MAAC	6,520	5,740	-12.0%	-0.8%	**-11.2%**
MAIN	7,060	7,680	8.8%	0.0%	**8.8%**
MAPP	3,160	3,910	23.7%	0.0%	**23.7%**
NPCC	6,220	6,710	7.9%	-3.2%	**11.1%**
SERC	20,690	17,950	-13.2%	0.0%	**-13.2%**
SPP	3,550	3,980	12.1%	0.0%	**12.1%**
WSCC	5,000	4,130	-17.4%	-17.2%	**-0.2%**
Total	**78,730**	**78,130**	**-0.8%**	**-1.6%**	**0.8%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-17: Variable Production Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	11.68	11.68	0.0%	-0.1%	**0.1%**
ERCOT	15.39	15.39	0.1%	0.0%	**0.1%**
FRCC	15.11	15.05	-0.4%	0.7%	**-1.1%**
MAAC	11.41	11.62	1.9%	0.0%	**1.9%**
MAIN	11.29	11.29	0.0%	0.0%	**0.0%**
MAPP	11.08	11.08	0.0%	0.0%	**0.0%**
NPCC	17.99	18.01	0.2%	-0.2%	**0.4%**
SERC	11.18	11.14	-0.3%	0.0%	**-0.3%**
SPP	11.99	11.99	0.0%	0.0%	**0.0%**
WSCC	16.16	15.58	-3.6%	3.9%	**-7.5%**
Total	**12.56**	**12.51**	**-0.3%**	**-0.3%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-18: Fuel Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	9.22	9.22	-0.1%	-0.1%	**0.0%**
ERCOT	12.76	12.77	0.1%	0.1%	**0.0%**
FRCC	12.60	12.50	-0.8%	0.9%	**-1.7%**
MAAC	9.24	9.45	2.3%	-0.1%	**2.4%**
MAIN	9.04	9.04	0.0%	0.0%	**0.0%**
MAPP	9.02	9.02	0.0%	0.0%	**0.0%**
NPCC	16.28	16.29	0.1%	-0.3%	**0.4%**
SERC	9.02	8.98	-0.5%	0.0%	**-0.5%**
SPP	9.80	9.80	0.0%	0.0%	**0.0%**
WSCC	14.13	13.43	-4.9%	4.3%	**-9.2%**
Total	**10.32**	**10.26**	**-0.5%**	**-0.5%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

B8-A.2.2 Individual Phase II Facilities

In addition to effects of the two alternative options in the group of Phase II facilities, there may be shifts in economic performance among individual facilities subject to section 316(b) regulation. To assess potential distributional effects, EPA analyzed facility-specific changes in generation, production costs, capacity utilization, revenue, and operating income. For each measure, EPA determined the number of Phase II facilities that would experience an increase or a reduction within three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more. Excluded from this analysis were facilities that would experience significant structural changes as a result of a policy option, including partial or full closures, avoided closures, or repowering. Table B8-A.19 presents the total number of Phase II facilities with different degrees of change in each of these measures under the waterbody/capacity-based option.

Table B8-A-19.— Operational Changes at Phase II Facilities from the Waterbody/Capacity-Based Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	9	20	11	3	4	14	451
Change in Variable Production Costs	7	3	2	17	22	2	373
Change in Capacity Utilization	5	4	6	10	4	8	475
Change in Total Revenue	62	21	8	64	16	22	318
Change in Operating Income	107	16	7	74	28	12	267

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10[th] of a percent.

[b] Of the 512 Phase II facilities, 86 facilities had zero generation in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 426 instead of 512 for this measure. One facility had zero revenues and operating income in the base case. As such, it was not possible to calculate its change in revenue or operating income. As a result, the number of facilities adds up to 511 instead of 512 for these measures.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.